Department of Public Utilities- DPU-RR-13

Question: Please explain the timing of the changes "well after 2000" in allowed emissions which may or not be triggered by adoption of EPA's proposed fine particulate ("FP") standard. Please compare those changes in allowed emissions called for be the Settlement Agreement. Please explain why you expect the timing you do (Hewson Rebuttal pg. 5 point 1).

After reviewing public comments, EPA officials hope to finalize the proposed FP standard by June 28, 1997 in order to comply with the court ordered deadline. EPA anticipates that the standard will then take 5 to 7 years to fully implement the stricter reduction requirements. Therefore, under EPA's projected schedule, the reduction requirements would likely become effective between 2002-2004. This timeline is earlier than EPA's prior estimate. Last April, EPA had estimated that sources would not enact reductions under the fine particulate state implementation plans until after 2005 (Attachment CEED-1).

However, many factors could further extend this compliance schedule. Congress will likely hold hearings on the FP standard as part of their recently acquired authority to review and approve/disapprove federal governmental regulations before they are finalized. If the proposal passes through Congressional review and is finalized, there are likely additional legal challenges. Given the response to the EPA proposal, the final standard will likely be challenged in Federal court by either environmental groups and/or the Air Quality Standards Coalition (a group representing 500 companies and associations). Upon passing the court test, States will be required to develop State Implementation Plans that must pass through public review and comment. The SIP development may take 3-5 years to complete. In this time, air quality models must be revised and pollutant transport and dispersion assumptions developed in order to demonstrate that the proposed SIP plans will bring areas into attainment. After a State SIP is adopted for fine particulates, the plan must then allow sufficient time for affected sources to plan, design and install required controls. Given the likely challenges and need for new modeling tools, my estimate for any reductions to comply with fine particulates standards would not be made until 2005-2010.

Under the Settlement Agreement, environmental reduction requirements for all but Brayton Point #3-4 would become effective before my estimated FP implementation date. Effective dates under the Settlement Agreement are as follows:

Effective Date

	for Stricter Environmental Limitations
Salem Harbor (all units)	2000
Brayton Point #1	2004
Brayton Point #2	2005
Brayton Point #3-4	2010

Response Prepared by Thomas A Hewson Jr.

Department of Public Utilities- DPU-RR-14

Question *Please provide EPA's November 29, 1996 Fact Sheet on the FP standard in its entirety (Hewson Rebuttal pg. 6 point 2).*

See Attachment CEED-2. The relevant data that EPA projected Massachusetts to be in attainment for the proposed fine particulates standard is contained in Table 5.

Response Prepared by Thomas A Hewson Jr.

<u>Department of Public Utilities- DPU-RR-15</u>

Question (a) Please explain how, when, where and how much (in your opinion) Title IV of the 1990 Clean Air Act will further reduce emissions of SO2 and NOx, compared to today (Hewson Rebuttal pg. 6 pt 3).

<u>Title IV SO2</u>: Under Title IV of the 1990 Clean Air Act, SO2 emission reductions are made in three steps. Beginning January 1, 1995, 261 listed units became subject to emission allowance limitations. Most affected units were located in the Midwest and Southeast. Beginning January 1, 2000, all utility steam units with capacities greater than 25 MW become affected units subject to emission allowance limitations. Annual emission allocations are set during this period at 9.48 million tons SO2/year. Finally beginning in 2010, 530,000 tons/year of allowance incentives provided to qualified utility units during 2000-2009 are discontinued thereby lowering the total utility emission allocation to 8.95 million tons per year. EVA estimates that total 1995 utility emissions were approximately 12.4 million tons per year or 3.5 million tons above the 2010 allocation.

<u>Title IV NOx</u>: When a utility coal-fired unit becomes an affected unit subject to SO2 standards, the units also becomes subject to Title IV NOx emission rate limitations as well. To comply with their NOx emission rate limitations, coal units must reduce emissions by approximately 40-60 percent. EVA has projected that these limitations will result in reducing NOx emissions by greater than 2.5 million tons. Since these reductions are limited to just coal-fired units, most Title IV NOx reductions will take place in the Midwest and Southeast. These reductions do not include the additional NOx reductions that will be triggered by state ozone attainment plans.

Question (b) Please provide details of how state actions to limit VOC's would reduce organic FP. How would this affect ground level ozone, if VOC/NOx ratios are about 14, per Andy Aiken's testimony?

According to EPA's Review Draft Report *<u>Air Quality Criteria for Particulate Matter</u>* (EPA/600/AP-95/001a), VOC emissions react to form secondary particulates which contribute to organic fine particulates loadings. Therefore, reducing VOC emissions should also reduce the secondary particulate formation of fine organic particulates.

All ambient air quality models that I have reviewed have shown that additional reductions in

VOC emissions made during the "ozone season" under the full range of ambient VOC/NOx ratios will reduce projected ground level ozone levels.

Response Prepared by Thomas A Hewson Jr.

Department of Public Utilities- DPU-RR-16

Question: Please provide a history of emission allowance prices, showing more detail for the last year. Are there any factors besides those mentioned in your testimony which have influenced or will influence allowance prices ? (Hewson Rebuttal pg. 7)

A history of emission allowance market prices is provided as Attachment CEED-3. I believe that my testimony properly characterized the major reasons for the current price trend. I have also tried to simplify reasons for future price increases. A detailed list of factors which could influence emission allowance prices is attached (CEED-4).

Response Prepared by Thomas A Hewson Jr.

Department of Public Utilities- DPU-RR-17

Question: Please explain what "the credit use for Phase II" means. (Hewson Rebuttal pg. 7 line 10)

The 1990 Clean Air Act allows utilities to carry-over any unused emission credits to future years. In 1995, utilities carried over 3.4 million tons of surplus allowance credits into 1996. Forecasters agree that this trend will continue until 1999. Beginning in 2000 at the beginning of Phase II when stricter emission limitations are imposed, most utilities are projected to switch from generated surplus allowances to consuming some of their carry-over allowances.

Response Prepared by Thomas A Hewson Jr.

Department of Public Utilities- DPU-RR-18

Questions: *Are there any major reasons besides PUC policies why utilities have not invested in cheap utilities now ? (Hewson Rebuttal pg. 7 line 12)*

Yes, as contained in my testimony, utilities have also been reluctant to invest in emission allowances that they may not consume for more than 5 years as part of a shorter term strategy to trim their expenditures.

Response Prepared by Thomas A Hewson Jr.

Department of Public Utilities- DPU-RR-19

Question: *Please provide a copy of the report At What Cost ? An Evaluation of the Proposed 37 State Seasonal NOx Control Program—Compliance Costs and Issues (November 1995).*

Copy is attached as CEED-5. NOx control technology performance and cost are shown in the report on pages 17 (SCR), 20 (SNCR), and 23 (Reburning)

Response Prepared by Thomas A Hewson Jr.

Department of Public Utilities- DPU-RR-20

Question: Are there ways to further reduce NOx emissions beside SCR and SNCR ? Are these other ways already "max'd out" at major New England fossil fuel units ? (Hewson Rebuttal pg. 8)

There are several methods beside SNCR and SCR to reduce NOx emissions. These techniques include: low NOx burners, over-fire air, fuel reburning, fuel biasing, flue gas recirculation and gas co-firing. Title IV of the Clean Air Act already requires the regional coal units to retrofit low NOx burners (SCR in case of PSNH Merrimack). Additional NOx reductions from the coal units to meet Title I (Ozone Non Attainment) provisions must come from post combustion controls or fuel reburning. Based upon the costs of these controls, we anticipate the coal units will find it more attractive to retrofit SCR and SNCR controls to meet Title I limits.

Oil/gas units were not subject to Title IV controls. However, Title I limitations will likely force them to retrofit come combustion controls listed above. Therefore for oil/gas units to create additional over-compliance credits, they would need to retrofit post combustion controls and/or reburning systems. However, with low baseline emissions from having poor capacity utilization their ability to create allowance credits is limited.

Response Prepared by Thomas A Hewson Jr.

Department of Public Utilities- DPU-RR-21

Question: Please explain in more detail why SCR controls remove less NOx when input concentrations are lower. (Hewson Rebuttal pg. 9)

SCR controls can be designed to consistently remove 80 percent[1] of the NOx in the flue gas stream. Therefore, the higher the incoming NOx content, the more NOx that will be removed. For example, an 80 percent removal rate on a 2.0 #NOx/MMBtu flue gas stream is equal to 1.6 lb. NOx/MMBtu. The same performance on a 0.45 #NOx/MMBtu flue gas stream of a tangentially fired boiler with a low NOx burner would yield a removal rate of only 0.36 lb. NOx/MMBtu.

Response Prepared by Thomas A Hewson Jr.

[1] Higher removal rates may be possible but are generally cost prohibitive and difficult to maintain.

Department of Public Utilities- DPU-RR-22

Question Please capitalize your estimate of the cost of increased emission reductions required by the Settlement and provide a table showing the amounts and c/kWh per year at the plant level spread across NEP customers (using NEP generation extrapolated from MECO's 72.6% share shown in book 2).

As discussed in my original testimony, the successful buyer would reduce his bid by the present value of the increased environmental compliance costs plus a risk premium. As is shown in CEED-6, the present value of the increased environmental expenditures assuming a capital recovery target of 12 percent, 40 percent marginal tax rate and a 3 percent inflation rate is between $90-150 million depending upon the successful bidder's tax situation[2]. This amount would be paid by Massachusetts consumers through a lower residual value credit (Schedule 1 pg. 63 column 7) that effectively increases the contract termination charge. Assuming that the lowered residual credit would be spread evenly across 10 years (as proposed for the asset sales), the amount of lower residual value credit (increased termination charge) associated with the additional environmental requirements are as follows.

	Amount MECO Sales (Gwh)	MECO Share (72.6%) of Lower Residual Value from Increased Environmental Req		Increased Termination Charge mills/kWh
		Low	High	Range
1998	16,255	$ 6.42 million	10.70 million	0.39-0.66
1999	16,576	$ 6.42	10.70	0.39-0.65
2000	16,899	$ 6.42	10.70	0.38-0.63
2001	17,131	$ 6.42	10.70	0.37-0.62
2002	17,349	$ 6.42	10.70	0.37-0.62
2003	17,603	$ 6.42	10.70	0.36-0.61
2004	17,913	$ 6.42	10.70	0.36-0.60
2005	18,233	$ 6.42	10.70	0.35-0.59
2006	18,547	$ 6.42	10.70	0.35-0.58
2007	18,845	$ 6.42	10.70	0.34-0.57

In addition to the higher contract termination charge outlined above, consumers will also pay a higher market power price to cover the Settlement Agreement's higher environmental control costs whenever the Salem Harbor or Brayton Point units are the price setting generating units.

[2] If bidder has carryover tax losses or unused tax credits, the net present value of the increased environmental expenditures would be in the upper part of the range. If the bidder has no tax credits or carryover losses, the net present value would fall into the lower part of range.

Response Prepared by Thomas A Hewson Jr.